BART Analysis for PSNH Merrimack Station Unit MK2

1. INTRODUCTION

PSNH Merrimack Station has two coal-fired steam-generating boilers that operate nearly full time to meet baseload electric demand. Unit MK2 is a wet-bottom, cyclone-type boiler with a heat input rating of 3,473 MMBtu/hr and an electrical output of 320 MW. Installed in 1968, this generating unit is equipped with selective catalytic reduction to remove oxides of nitrogen (NO_X) formed during the combustion process. Two electrostatic precipitators operate in series to capture particulate matter (PM) in the flue gases. Also, construction has begun on a scrubber system that will reduce sulfur dioxide (SO_2) emissions. Retrofit options for this unit are limited because the facility already has controls in place for NO_X and PM, and only a few emission control technologies are compatible with the type of boiler design employed.

2. CURRENTLY AVAILABLE RETROFIT TECHNOLOGIES, POTENTIAL COSTS, AND OTHER ENVIRONMENTAL AND ENERGY IMPACTS

2.1 Retrofit Technologies for NO_X Control

The only NO_X control technology options available and potentially applicable to Unit MK2 are selective non-catalytic reduction and selective catalytic reduction.

Selective Non-Catalytic Reduction (SNCR)

SNCR is a post-combustion technology that involves injecting ammonia or urea into specific temperature zones in the upper furnace or convective pass. The ammonia or urea reacts with NO_X in the flue gas to produce nitrogen and water. The effectiveness of SNCR depends on the temperature where reagents are injected, the mixing of the reagent in the flue gas, the residence time of the reagent within the required temperature window, the ratio of reagent to NO_X, and the sulfur content of the fuel that may create sulfur compounds that deposit in downstream equipment. NO_X reductions of 35 to 60 percent have been achieved through the use of SNCR on coal-fired boilers operating in the United States.

Selective Catalytic Reduction (SCR)

SCR is another post-combustion technology that involves injecting ammonia into the flue gas in the presence of a catalyst to reduce NO_X to nitrogen and water. The SCR reactor can be located at various positions in the process, including upstream of an air heater and particulate control device, or downstream of an air heater, particulate control device, and flue gas desulfurization system. The performance of SCR is influenced by flue gas temperature, fuel sulfur content, ammonia-to-NO_X ratio, inlet NO_X concentration, space velocity, catalyst design, and catalyst condition. NO_X emission reductions of about 75 to 90 percent have been obtained with SCR on coal-fired boilers operating in the U.S.

2.1.1 Potential Costs of NO_X Controls

The estimated costs of NO_X emission controls for SNCR and SCR at Merrimack Station Unit MK2 are presented in Table 2-1. These estimates are based on assumptions used in EPA's Integrated Planning Model for the EPA Base Case 2006 (V.3.0), for retrofitting an EGU the size of Unit MK2. For SNCR, the total annual cost is estimated to be about \$5,110,000, or \$593/ton of NO_X removed. For an SCR system, the total annual cost is estimated to be \$5,070,000, or \$312/ton. Stated costs are for year-round operation.

Table 2-1. Estimated NO_X Control Costs (2008 \$)

Control Technology	Capital Cost ($/kW)	Capital Cost $	O&M Cost ($/yr)	Total Annual Cost ($/yr)	Average Cost ($/ton)
SNCR	12.1	3,880,000	4,780,000	5,110,000	593
SCR	117.8	37,710,000	1,910,000	5,070,000	312

Estimates are derived from USEPA, *Documentation for EPA Base Case 2006 (V.3.0) Using the Integrated Planning Model*, November 2006. Costs are scaled for boiler size. All costs are adjusted to 2008 dollars. Total annual cost is for retrofit of a 320-MW unit with 80% capacity factor and 2,243 million kWh annual generation. Total annual cost includes amortization of capital cost over 15 years at 3.0% interest rate. Average cost per ton is based on an estimated 8,613 tons of NO_X removed for SNCR and an estimated 16,269 tons of NO_X removed for SCR.

Because Unit MK2 already has SCR controls in place, the listed costs serve for comparative purposes only. In 1998, PSNH estimated that its SCR costs would be about \$400/ton for year-round operation and about \$600/ton for operation limited to the ozone season (May 1 through September 30). These costs are approximately equal to \$530/ton and \$790/ton, respectively, in 2008 dollars. PSNH currently operates Unit MK2 full time in order to meet NO_X RACT requirements.

Year-round operation is EPA's presumptive norm for BART (applicable to EGUs of 750 MW capacity or greater) for units that already have seasonally operated SCRs. Assuming that operating costs are proportional to operating time, the difference in cost between year-round and seasonal SCR operation for Unit MK2 is about \$3,300,000, based on PSNH's 1998 cost estimates. The cost differential could be about half that amount, if based on the current (but more generic) estimates presented in Table 2-1.

2.1.2 Other Environmental and Energy Impacts of NO_X Controls

SNCR and SCR both use urea or anhydrous ammonia. Ammonia is a regulated toxic air pollutant in New Hampshire. Facilities using these technologies must limit their ammonia emissions, which may be released either in their flue gases or as fugitive emissions from the handling and storage of urea or anhydrous ammonia. A facility must also maintain a risk management plan if the quantities of stored ammonia exceed the applicable regulatory threshold.

Ammonia from SNCR that becomes entrained in the fly ash may affect the resale value or disposal cost of the ash. Ammonia in the flue gas may produce a more visible plume, depending on the ammonia concentration in the gas stream. High ammonia concentrations in the boiler from SNCR can react with sulfate to form ammonium bisulfate, which deposits on the economizer, air heater, and other surfaces. Ammonium bisulfate can also plug filter bags in a baghouse. SNCR may generate nitrous oxide emissions, a greenhouse gas.

With SCR, the formation of ammonium bisulfate may be exacerbated by the ability of this catalyst-based technology to oxidize SO_2 to SO_3, resulting in higher sulfate concentrations than would otherwise exist. Ammonium bisulfate formation can be reduced by controlling excess ammonia and using catalysts that minimize SO_2 oxidation. The air heater and other surfaces where the ammonia bisulfate may deposit must be washed periodically. Washing helps to maintain the efficiency of the air heater and prevents plugging to allow the free flow of flue gases through it. An SCR may also require a fan upgrade to overcome additional pressure drop across the catalyst. The increase in fan capacity consumes a small amount of energy.

NO_X emission reductions provide environmental and public health benefits beyond visibility improvement – most notably, reductions in acid rain and ground-level ozone. NO_X is a chemical precursor to ozone formation and is one of the primary compounds contributing directly to acid rain formation. A decrease in acid rain production improves water quality and the health of ecosystems sensitive to low pH.

2.2 Retrofit Technologies for PM Control

PM control technologies available and potentially applicable to Unit MK2 are electrostatic precipitators, fabric filters, mechanical collectors, and particle scrubbers.

Electrostatic Precipitators (ESPs)

Electrostatic precipitators capture particles through the use of electrodes, which are electrical conductors used to make contact with a non-metallic part of a circuit. An ESP consists of a small-diameter negatively charged electrode (usually a set of individual wires or a grid) and a grounded positively charged plate. In operation, a strong electric charge from the negatively charged electrode sets up a one-directional electric field. When particle-laden gases pass through this electric field, the particles become charged and are then drawn to the positive collecting surface (the plate), where they are neutralized. The particles are then collected by washing or knocking the plate, causing the particles to fall into a collection hopper. Existing electrostatic precipitators are typically 40 to 60 percent efficient. New or rebuilt ESPs can achieve collection efficiencies of more than 99 percent.

Fabric Filters

Fabric filtration devices, or baghouses, incorporate multiple fabric filters/bags inside a containment structure. These devices work on the same principal as a vacuum cleaner bag. The particle removal efficiency of the fabric filter system depends on a variety of particle and operational parameters. The physical characteristics of particle size distribution, particle cohesion, and particle electrical resistivity are important variables. Operational parameters affecting collection efficiency include air-to-cloth ratio, operating pressure loss, cleaning sequence, interval between cleanings, and cleaning intensity. The structure of the fabric filter, filter composition, and bag properties also affect collection efficiency. Collection efficiencies of baghouses may exceed 99 percent.

Mechanical Collectors and Particle Scrubbers

Mechanical collectors, such as cyclones, are most effective at collecting coarse particulate matter (i.e., particles with a diameter of 10 micrometers or larger). Finer particles escape cyclones along with the flue gases. For this reason, mechanical collectors are generally most useful when used in conjunction with other pollution control equipment. The typical collection efficiency of mechanical collectors is about 85 percent for larger particle sizes.

Scrubbing systems involve the injection of water and/or chemicals into the flue gas to wash unwanted pollutants from the gas stream through physical or chemical absorption/adsorption. Scrubbing systems have been shown to reduce PM_{10} emissions by 50 to 60 percent but are generally less effective for removal of fine particles.

Because mechanical collectors and particle scrubbers are more costly and less efficient than other control options (i.e., ESPs, baghouses), these lower-performing technologies are rarely used today for removing particulate matter from power plant emissions. Consequently, mechanical collectors and scrubbers are not considered further in this analysis.

2.2.1 Potential Costs of PM Controls

Table 2-2 presents cost data for PM controls as developed from NESCAUM's *Assessment of Control Technology Options for BART-Eligible Sources*, March 2005. Approximate cost ranges are provided for two types of ESPs and two types of fabric filters applicable to a retrofit installation the size of Unit MK2. Capital and operating costs are based on flue gas flow rates in actual cubic feet per minute (acfm).

Table 2-2. Estimated PM Control Costs (2008 $)

Control Technology	Capital Cost ($/kW)	Capital Cost $	O&M Cost ($/yr)	Total Annual Cost ($/yr)	Average Cost ($/ton)
Dry ESP	73-194	23.3-62.1 million	1.1-1.9 million	3.0-7.1 million	100-240
Wet ESP	73-194	23.3-62.1 million	0.6-1.6 million	2.6-6.8 million	90-230
Fabric filter - reverse air	82-194	26.4-62.1 million	1.6-2.4 million	3.8-7.6 million	130-260
Fabric filter - pulse jet	58-194	18.6-62.1 million	2.2-3.1 million	3.7-8.3 million	130-280

Reference: NESCAUM, *Assessment of Control Technology Options for BART-Eligible Sources*, March 2005. All costs are adjusted to 2008 dollars. Total annual cost is for retrofit of a 320-MW unit with 80% capacity factor and flue gas flow rate of 1.36 million acfm. Total annual cost includes amortization of capital cost over 15 years at 3.0% interest rate. Average cost per ton is based on 29,850 tons of PM removed for ESPs and 29,759 tons of PM removed for fabric filters.

The costs for ESPs and fabric filters are of similar magnitude, with total annual costs ranging from about \$2.6 million to \$8.3 million, or \$90 to \$280 per ton of PM removed. Because Unit MK2 already has two dry ESPs installed and operating, the tabulated costs are useful for comparative purposes only.

2.2.2 Other Environmental and Energy Impacts of PM Controls

PM controls collect particulate matter, or fly ash, suspended in the flue gases. In some cases, the fly ash is injected back into the boiler, an arrangement that improves boiler efficiency by recapturing the residual heating value of the fly ash. If the fly ash is not reinjected, it must be either landfilled or reclaimed, e.g., as a supplement in concrete production or as a component in other manufactured products.

2.3 Retrofit Technologies for SO_2 Control

SO_2 control technologies available and potentially applicable to Unit MK2 are wet flue gas desulfurization and use of low-sulfur coal.

Wet Flue Gas Desulfurization

The flue gas desulfurization (FGD) process – commonly known as "scrubber" technology – uses an alkaline reagent to absorb SO_2 in the flue gas. For coal-fired power plants, the reagent is usually lime or limestone; and the reaction product is calcium sulfite or calcium sulfate. The solid compounds are collected and removed in downstream process equipment. Calcium sulfate (gypsum) sludge produced in FGDs can be recycled into saleable byproducts such as wallboard, concrete, and fertilizer. Sulfate products that are not recycled must be landfilled.

The FGD process may be either dry (injection of the chemical reagent in dry form) or wet (application of the reagent in liquid or slurry form). To date, wet scrubbers are more commonly used, with alkali slurries as the SO_2 absorbent medium. Lime/limestone scrubbers, sodium scrubbers, and dual alkali scrubbers are among the commercially proven wet FGD systems. SO_2 removal efficiencies for existing wet limestone scrubbers range from 31 to 97 percent, with an average of 78 percent (NESCAUM, 2005). Scrubbers may also be effective for the removal of particulate matter, mercury, and other air pollutants. Wet regenerable (meaning the reagent material can be treated and reused) FGD processes are an attractive option because they allow higher sulfur removal rates and produce minimal wastewater discharges.

Low-Sulfur Coal

Because SO_2 emissions are directly related to the sulfur content of the fuel burned, reducing the amount of sulfur in the fuel reduces SO_2 emissions. Usually, for operational reasons, a facility cannot make a complete switch from one fuel type to another. Instead, the facility may be able to blend different fuels to obtain a lower-sulfur mix that emits less SO_2 upon combustion – for example, blending low-sulfur bituminous or subbituminous coal with a high-sulfur bituminous coal. The feasibility of fuel switching or blending depends on the physical characteristics of the plant, and significant modifications to systems and equipment may be necessary to accommodate the change in fuels. Switching to a lower-sulfur coal can affect coal handling systems, ash handling systems, boiler performance, and the effectiveness of PM controls. To meet federal acid rain requirements, many facilities have switched to lower-sulfur coals, resulting in SO_2 emission reductions of 50 to 80 percent.

2.3.1 Potential Costs of SO_2 Controls

PSNH Merrimack Station is required by New Hampshire law to install an FGD system to reduce mercury emissions (with SO_2 removal as a co-benefit) at both Unit MK1 and Unit MK2. The company's recently revised estimate for the project places the capital cost at $457 million, or $1,055/kW (both amounts in 2008 $) to install a wet limestone FGD system. Using 2002 baseline emissions of 30,657 tons of SO_2 from Units MK1 and MK2 combined, and a minimum capture efficiency of 90 percent for this pollutant, the annualized capital cost equates to about $1,400 per ton of SO_2 removed.

The project cost is said to be in line with the costs of multiple-unit scrubber installations occurring elsewhere in the country. However, PSNH's estimated cost per kilowatt is at least triple the cost range for FGD systems as reported in MACTEC Federal Programs, Inc., "Assessment of Reasonable Progress for Regional Haze in MANE-VU Class I Areas," Final, July 9, 2007 (see Reasonable Progress Report, Attachment Y). The PSNH estimated cost is also more than double the recent estimate of $300/kW to $500/kW as reported in a 2008 survey of FGD systems (George W. Sharp, "What's That Scrubber Going to Cost?," *Power*, March 1, 2009). The higher cost-per-kW for Unit MK2 may reflect recent industry-wide increases in raw material, manufacturing, and construction costs.

The costs of switching to lower-sulfur coal at PSNH Merrimack Station would rest on the incremental cost of purchasing the lower-sulfur material at prevailing market prices. Even if a lower-sulfur coal is available at reasonable additional cost, operational considerations may dictate the choice of coal for Unit MK2. (Only certain types of coal can be used in wet-bottom, cyclone boilers.) Commodity spot prices for coal vary considerably. For example, from late March to early May 2009, the price spread between Northern Appalachia coal (<3.0 SO_2) and Central Appalachia coal (1.2 SO_2) ranged from $10 to $25 per ton (source: Energy Information Administration, http://www.eia.doe.gov/fuelcoal.html).

2.3.2 Other Environmental and Energy Impacts of SO_2 Controls

An FGD system typically operates with high pressure drops across the control equipment, requiring increased energy usage for blowers and circulation pumps. Some configurations of FGD systems also require flue gas reheating to prevent physical damage to the equipment, resulting in higher fuel usage. IPM documentation indicates that a wet FGD system reduces the generating capacity of the unit by about 2 percent.

Flue gas desulfurization has impacts on the operation of solid waste and wastewater management systems. In addition to removing SO_2, the FGD process removes mercury and other metals and solids. Often, gypsum produced in a limestone FGD process is recycled or sold to cement manufacturers; otherwise, the sludge must be stabilized and placed in an approved landfill. Gypsum must be dewatered before it can be handled, resulting in a wastewater stream that requires treatment. This wastewater increases the sulfates, metals, and solids loadings on the receiving wastewater treatment plant. Sometimes a clarifier is required to remove wastewater solids coming from the FGD system.

Wet FGDs increase the amount of water vapor entrained in the flue gas. The result is a more visible plume at the stack outlet.

3. DISCUSSION OF CURRENT POLLUTION CONTROL EQUIPMENT AND EMISSIONS

3.1 Discussion of Current NO_X Emissions and Controls

In 1994, PSNH installed an SCR system on Unit MK2, the first such system to be used on a coal-fired wet-bottom cyclone boiler in the U.S. Designed to meet NO_X Reasonably Available Control Technology (RACT) limits, the SCR has reduced NO_X emissions by 85 to 92 percent. Unit MK2 is also required to meet a federal acid rain limit of 0.86 lb NO_X /MMBtu, an additional NO_X RACT Order limit of 15.4 tons per calendar day, and a NO_X RACT Order limit of 29.1 tons per calendar for Units MK1 and MK2 combined. PSNH is allowed to meet the 15.4 ton-per-day limit for Unit MK2 by using ozone-season discrete emission reductions (DERs). In 2002, actual NO_X emissions for Unit MK2 were reported as 2,871 tons.

3.2 Discussion of Current PM Emissions and Controls

PSNH Merrimack Station Unit MK2 has two electrostatic precipitators (ESPs), dry type, operating in combination with a fly ash reinjection system. Installation of the ESPs has reduced PM emissions from this unit by about 99 percent, based on a review of 2002 emissions data. The current air permit for the facility requires that Unit MK2 meet a total suspended particulate (filterable TSP) limit of 0.227 lb/MMBtu and a TSP emissions cap of 3,458.6 tons/year. Actual TSP emissions from this unit were 210 tons in 2002.

3.3 Discussion of Current SO_2 Emissions and Controls

New Hampshire law requires PSNH Merrimack Station to install and operate a scrubber system for both MK1 and MK2 by July 1, 2013. While the primary intent of this law is to reduce mercury emissions from the company's coal-fired power plants, a major co-benefit is SO_2 removal. Pursuant to this statutory obligation, New Hampshire issued a permit to PSNH on March 9, 2009, for the construction of a wet, limestone-based FGD system to control mercury and SO_2 emissions at Merrimack Station. The permit requires an SO_2 control level of at least 90 percent for Unit MK2. The specific language of the permit states as follows:

> "Beginning on July 1, 2013,…SO_2 emissions shall be controlled to 10 percent of the uncontrolled SO_2 emission rate (90 percent SO_2 removal)…The Owner shall submit a report no later than December 31, 2014 that includes the calendar month average SO_2 emission rates at the inlet and outlet of the FGD and the corresponding calendar month average emissions reductions during the preceding 12 months of operation,…DES will use this data to establish the maximum sustainable rate of SO_2 emissions reductions for MK2. The maximum sustainable rate is the highest rate of reductions that can be achieved 100 percent of the time...This established rate shall be incorporated as a permit condition for MK2. Under no circumstances shall the SO_2 removal efficiency for MK2 be less than 90 percent."

These permit conditions effectively require that actual SO_2 removal efficiencies *exceed* 90 percent on average for Unit MK2. This plant must also meet general regulations for coal-burning devices that limit the sulfur content of the coal to 2.0 pounds per million BTU gross heat content averaged over any consecutive 3-month period, and 2.8 pounds per million BTU gross heat content at any time. Since 2002, the facility has operated well within these fuel limits. PSNH must also meet a fleet-wide SO_2 emissions cap of 55,150 tons/year effective for all electrical generating units at its Merrimack, Newington, and Schiller Stations. In 2002, actual SO_2 emissions from Unit MK2 were 20,902 tons.

4. REMAINING USEFUL LIFE OF UNIT

Where a reasonable control option is available for a BART-eligible unit, the unit should be controlled in a manner consistent with BART and the expected useful life of the unit. Originally, electric generating units were estimated to have a life expectancy of 30 to 40 years, but many units are lasting 50 years or more. In many cases, it is less expensive to keep existing units operating than to build replacement facilities and/or new transmission lines. Merrimack Station Unit MK2 was built in 1968. PSNH's commitment to install new emission controls on this unit demonstrates the company's belief that this unit is capable of supplying electricity to the region for many years beyond the present.

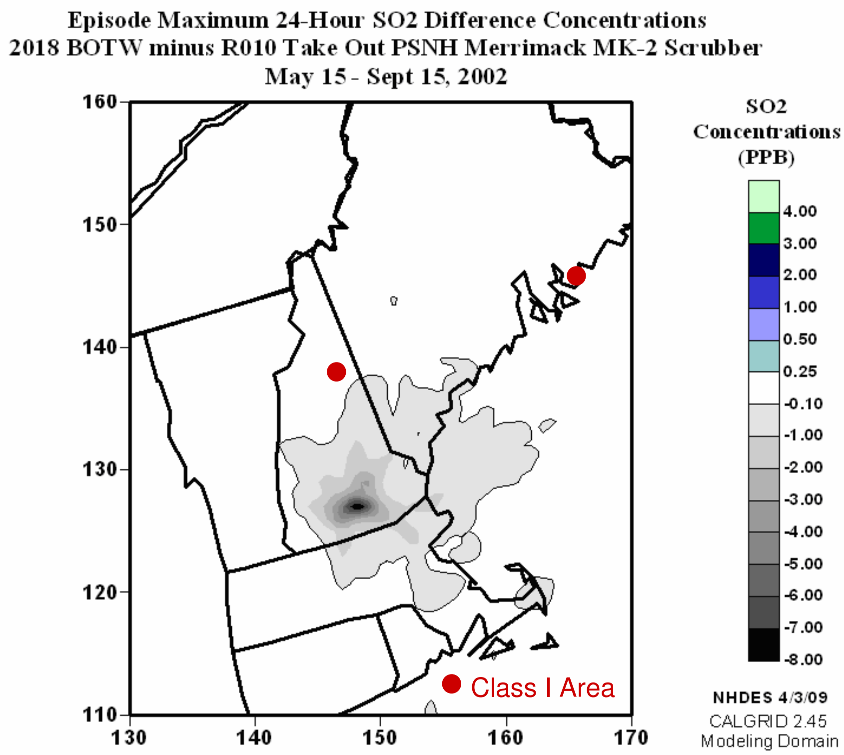
5. DEGREE OF VISIBILITY IMPROVEMENT ANTICIPATED FROM BART

The New Hampshire Department of Environmental Services (NHDES) conducted a screening-level analysis of the anticipated visibility effects of BART controls at PSNH Merrimack Station Unit MK2. Specifically, one modeling run using the CALGRID photochemical air quality model was performed to assess the effects of installing an FGD system on Unit MK2. The simulation covered the full summer modeling episode (from May 15 to September 15, 2002) with MANE-VU's 2018 beyond-on-the-way (BOTW) emissions inventory scenario as a baseline. The BOTW emissions scenario reflects controls from potential new regulations that may be necessary to attain National Ambient Air Quality Standards and other regional air quality goals, beyond those regulations that are already "on the books" or "on the way."

The CALGRID model outputs took the form of ambient concentration reductions for SO_2, $PM_{2.5}$, and other haze-related pollutant within the region. NHDES post-processed the modeled concentration reductions to estimate the corresponding visibility improvements at Class I areas such as Acadia National Park, Moosehorn National Wildlife Refuge, and Lye Brook Wilderness Area (i.e., concentration impacts were converted to visibility impacts). Visibility can be quantified using deciviews, a logarithmic unit of measure to describe increments of visibility change that are just perceptible to the human eye

Based on the modeling results, the installation of scrubber technology with 90-percent removal efficiency on Unit MK-2 is expected to reduce maximum predicted 24-hour average SO_2 concentration impacts by up to 21 $\mu g/m^3$ (8 ppb by volume; see Figure 5-1) and maximum predicted 24-hour average $PM_{2.5}$ concentration impacts by up to 1 $\mu g/m^3$. The largest modeled pollutant concentration reductions occur within a 50-kilometer radius of the facility. For the affected Class I areas (located 100 to 500 kilometers away), reductions in the maximum predicted concentrations of SO_2, $PM_{2.5}$, and other haze-related pollutants, combined, are expected to yield a nominal improvement in visibility (about 0.1 deciview) on direct-impact hazy days.

Figure 5-1



6. DETERMINATION OF BART

Based on the completed review and evaluation of existing and potential control measures for PSNH Merrimack Station Unit MK2, it is determined that the NO_X, PM, and SO_2 controls described below represent Best Available Retrofit Technology for this unit.

6.1 Selecting a Pollution Control Plan for NO_X

PSNH currently operates an SCR system on Unit MK2. This system was installed in 1994 to meet the requirements of NO_X RACT and the ozone season NO_X budget program. SNCR is the only other control technology available for controlling NO_X emissions from this unit. SCR yields higher NO_X removal rates and is more cost-effective than SNCR. PSNH estimated, in 1998, that the existing SCR system could be operated year-round at a cost of \$494 per ton of NO_X removed. Because the SCR system is already in place to meet other air program requirements and can be operated year-round at reasonable cost, full-time operation of the existing SCR is considered to be BART for NO_X control on Unit MK2.

6.2 Selecting a Pollution Control Plan for PM

PSNH currently operates two ESPs, in series, on Unit MK2. Mechanical collectors (cyclones) are effective only for coarse particle removal and would be impractical as a retrofit for Unit MK2, where the more efficient ESPs already exist. Fabric filters have performance levels comparable to ESPs and are a suitable PM control technology for power plant emissions.

However, fabric filters are also impractical as a retrofit for Unit MK2 under present circumstances: ESPs already exist, physical space at the facility is limited, and the addition of an FGD system is now in progress. The existing ESPs, operating in conjunction with the FGD process, will provide the most cost-effective controls for particulate emissions. Therefore, continued operation of the existing ESPs is considered to be BART for PM control on Unit MK2.

6.3 Selecting a Pollution Control Plan for SO_2

PSNH Merrimack Station is installing a flue gas desulfurization system to remove mercury emissions in compliance with New Hampshire law. As a co-benefit, the FGD system is expected to remove more than 90 percent of SO_2 emissions. Because this installation is already mandated and because it will attain SO_2 removal rates approaching the BART presumptive norm of 95 percent (applicable to EGUs substantially larger than Merrimack Station), the FGD system is considered to be BART for SO_2 control on Unit MK2. (Note that at an installed cost exceeding $1,000/kW, the FGD system is more expensive than the industry average).

7. SUMMARY AND CONCLUSIONS

Table 7-1 summarizes best available retrofit technology for PSNH Merrimack Station Unit MK2 for the pollutants NO_X, PM, and SO_2. The summary includes existing controls considered as meeting or exceeding BART requirements as well changes in progress that are consistent with the BART rule. Because NHDES has already issued a temporary permit (construction permit) for the installation of the flue gas desulfurization system, NHDES is not requesting further action of Merrimack station at this time in order to comply with BART.

Table 7-1. Summary of BART Determinations for Unit MK2

Pollutant	Current Emission Controls	Additional Emission Controls in Progress	BART
NO_X	SCR	None	SCR
PM	Two ESPs	None	Two ESPs
SO_2	Fuel sulfur limits set at 2.0 lb sulfur/MMBtu (averaged over 3 mos.) and 2.8 lb sulfur/MMBtu at any time.	Flue gas desulfurization (FGD), with required SO_2 reduction set at maximum sustainable rate, but no less than 90% average.	Flue gas desulfurization (FGD), with required SO_2 reduction set at maximum sustainable rate, but no less than 90% average; current fuel sulfur limits to remain in effect.

NEW HAMPSHIRE BART ANALYSIS: Merrimack Station Unit MK2 (320 MW)

Pollutant	Emission Control Technology	Control Level	Uncontrolled Emissions ton/yr	Controlled Emissions ton/yr	Emission Reductions ton/yr	Estimated Cost of Emission Controls[7]						
							Capital $	Capital $/kW	O&M $/yr	Total Annual $/yr	Average $/ton	Ref.
NO_X	SCR (existing)	85%	19,140 [1]	2,871 [2]	16,269		37,710,186	118	1,910,432	5,069,414	312	8
	SNCR	45%	19,140 [1]	10,527	8,613		3,876,771	12	4,781,136	5,105,893	593	8
PM	2 ESPs (existing)	99+%	30,060 [2]	210 [2]	29,850	min.	23,280,363	73	1,086,417	2,571,006	86	9
						max.	62,080,967	194	1,940,030	7,140,553	239	
	Fabric Filters	99%	30,060 [2]	301	29,759	min.	18,624,290	58	2,172,834	3,732,991	125	9
						max.	62,080,967	194	3,104,048	8,304,571	279	
SO_2	Lower-S coal (existing)	40% [3]	—	—	—		—	—	—	—	—	
	FGD	90% [4]	20,902 [5]	2,090	18,812 [6]		457,000,000	1,055	unknown	unknown	unknown	10

1 Estimated.

2 2002 (baseline) emissions as taken from NHDES data summary derived from facility's annual emissions statement.

3 Estimated average reduction in fuel sulfur content with use of lower-S coal, resulting in equivalent reduction in SO_2 emissions.

4 Additional control level on emissions after existing controls have been applied; overall control level with use of lower-S coal is estimated to be 40 + 90(1 - 0.40) = 94%

5 2002 (baseline) emissions with use of lower-sulfur coal at ~1.0 % S by weight.

6 Reductions from baseline emissions.

7 All cost estimates adjusted to 2008 $.

8 USEPA, *Documentation for EPA Base Case 2006 (V.3.0) Using the Integrated Planning Model*, November 2006.

9 NESCAUM, *Assessment of Control Technology Options for BART-Eligible Sources*, March 2005.

10 FGD capital cost is PSNH's estimate (2008$) for Units MK1 (113 MW) and MK2 (320 MW) combined.

Merrimack Station Unit MK2: NO_X Controls

Plant type	wet-bottom, cyclone, coal-fired boiler	
Generation capacity	320	MW
Maximum heat Input	3,473	MMBtu/hr
Capacity factor	80	%
Annual hours	8,760	hr/yr
Annual production	2,242,560,000	kWh/yr

Historical operation:

Year	2002	2003	2004	2005	2006	2007	2008
Operating hours	7,180	6,703	7,462	7,280	7,577	7,477	6,519
Total Heat Input*	22,013,513	22,006,524	24,024,382	23,795,575	25,328,218	25,448,437	18,282,000
Capacity factor**	72.4%	72.3%	79.0%	78.2%	83.3%	83.6%	60.1%

*MMBtu (from CEM data) **Based on ratio of total heat input to theoretical maximum heat input

Costs: 2004 $

Control Technology	Capital	Scaled Capital	Total Capital	Total Annualized Capital	Fixed O&M	Scaled Fixed O&M		Variable O&M	Scaled Variable O&M		Total Fixed & Variable O&M	Total Annualized Cost	Emission Reductions	Average Cost
	$/kW	$/kW	$	$/yr	$/kW/yr	$/kW/yr	$/yr	mills/kWh	mills/kWh	$/yr	$/yr	$/yr	tons/yr	$/ton
SCR	111.48	103.46	33,108,152	2,773,470	0.74	0.69	219,771	0.67	0.65	1,457,518	1,677,289	4,450,759	16,269	274
SNCR	11.04	10.64	3,403,662	285,125	0.16	0.15	49,328	1.46	1.85	4,148,332	4,197,661	4,482,786	8,613	520

Costs: 2008 $ 2004 $ → 2008 $ 1.139 multiplier

Control Technology	Capital	Scaled Capital	Total Capital	Total Annualized Capital	Fixed O&M	Scaled Fixed O&M		Variable O&M	Scaled Variable O&M		Total Fixed & Variable O&M	Total Annualized Cost	Emission Reductions	Average Cost
	$/kW	$/kW	$	$/yr	$/kW/yr	$/kW/yr	$/yr	mills/kWh	mills/kWh	$/yr	$/yr	$/yr	tons/yr	$/ton
SCR	126.98	117.84	37,710,186	3,158,982	0.84	0.78	250,319	0.76	0.74	1,660,113	1,910,432	5,069,414	16,269	312
SNCR	12.57	12.11	3,876,771	324,757	0.18	0.18	56,185	1.66	2.11	4,724,951	4,781,136	5,105,893	8,613	593

Cost Reference:

USEPA, *Documentation for EPA Base Case 2006 (V.3.0) Using the Integrated Planning Model*, November 2006.

Annualized cost basis:

Period, yrs	15
Interest, %	3.0
CRF	0.08377

Merrimack Station Unit MK2: PM Controls

Plant type	wet-bottom, cyclone, coal-fired boiler	
Capacity	320	MW
Maximum heat Input	3,473	MMBtu/hr
Capacity factor	80	%
Annual hours	8,760	hr/yr
Annual production	2,242,560,000	kWh/yr
Flue gas flow rate	1,362,620	acfm

Historical operation:

Year	2002	2003	2004	2005	2006	2007	2008
Operating hours	7,180	6,703	7,462	7,280	7,577	7,477	6,519
Total Heat Input*	22,013,513	22,006,524	24,024,382	23,795,575	25,328,218	25,448,437	18,282,000
Capacity factor**	72.4%	72.3%	79.0%	78.2%	83.3%	83.6%	60.1%

*MMBtu (from CEM data)

**Based on ratio of total heat input to theoretical maximum heat input

Costs: 2004 $

Control Technology		Capital $/acfm	Total Capital $	Total Annualized Capital $/yr	Fixed O&M $/yr-acfm	Variable O&M $/yr-acfm	Total Fixed & Variable O&M $/yr	Total Annualized Cost $/yr	Emission Reductions tons/yr	Average Cost $/ton
Dry ESP	min.	15.00	20,439,300	1,712,200	0.25	0.45	953,834	2,666,034	29,850	89
	max.	40.00	54,504,800	4,565,867	0.65	0.60	1,703,275	6,269,142	29,850	210
Wet ESP	min.	15.00	20,439,300	1,712,200	0.15	0.25	545,048	2,257,248	29,850	76
	max.	40.00	54,504,800	4,565,867	0.50	0.50	1,362,620	5,928,487	29,850	199
Fabric Filter - Reverse Air	min.	17.00	23,164,540	1,940,494	0.35	0.70	1,430,751	3,371,245	29,759	113
	max.	40.00	54,504,800	4,565,867	0.75	0.80	2,112,061	6,677,928	29,759	224
Fabric Filter - Pulse Jet	min.	12.00	16,351,440	1,369,760	0.50	0.90	1,907,668	3,277,428	29,759	110
	max.	40.00	54,504,800	4,565,867	0.90	1.10	2,725,240	7,291,107	29,759	245

Cost Reference:

NESCAUM, *Assessment of Control Technology Options for BART-Eligible Sources*, March 2005.

Annualized cost basis:

Period, yrs	15
Interest, %	3.0
CRF	0.08377

Costs: 2008 $ 2004 $ → 2008 $ 1.139 multiplier

Control Technology		Capital $/acfm	Total Capital $	Total Annualized Capital $/yr	Fixed O&M $/yr-acfm	Variable O&M $/yr-acfm	Total Fixed & Variable O&M $/yr	Total Annualized Cost $/yr	Emission Reductions tons/yr	Average Cost $/ton
Dry ESP	min.	17.09	23,280,363	1,950,196	0.28	0.51	1,086,417	3,036,613	29,850	102
	max.	45.56	62,080,967	5,200,523	0.74	0.68	1,940,030	7,140,553	29,850	239
Wet ESP	min.	17.09	23,280,363	1,950,196	0.17	0.28	620,810	2,571,006	29,850	86
	max.	45.56	62,080,967	5,200,523	0.57	0.57	1,552,024	6,752,547	29,850	226
Fabric Filter - Reverse Air	min.	19.36	26,384,411	2,210,222	0.40	0.80	1,629,625	3,839,848	29,759	129
	max.	45.56	62,080,967	5,200,523	0.85	0.91	2,405,637	7,606,160	29,759	256
Fabric Filter - Pulse Jet	min.	13.67	18,624,290	1,560,157	0.57	1.03	2,172,834	3,732,991	29,759	125
	max.	45.56	62,080,967	5,200,523	1.03	1.25	3,104,048	8,304,571	29,759	279

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BART Analysis for
PSNH Newington Station Unit NT1

1. INTRODUCTION

Unit NT1 is the sole electrical generating unit at PSNH Newington Station. It operates at irregular times, principally during periods of peak electric demand. Power is derived from an oil- and/or natural-gas-fired steam-generating boiler with a heat input rating of 4,350 MMBtu/hr and an electrical output of 400 MW. Installed in 1968, the boiler is equipped with low-NO_X burners, an overfire air system, and water injection to minimize the formation of oxides of nitrogen (NO_X) during the combustion process. The facility also has an electrostatic precipitator to capture particulate matter (PM) in the flue gases. Partial control of SO_2 emissions is provided by sulfur content limits on the fuel oil.

2. CURRENTLY AVAILABLE RETROFIT TECHNOLOGIES, POTENTIAL COSTS, AND OTHER ENVIRONMENTAL AND ENERGY IMPACTS

2.1 Available Retrofit Technologies for NO_X Control

NO_X control technology options available and potentially applicable to Unit NT1 are combustion controls, selective non-catalytic reduction, and selective catalytic reduction.

Combustion Controls

Controls on the combustion process can reduce NO_X formation by as much 75 percent. Combustion controls or firing practices include such measures as staged combustion, limiting excess air, providing overfire air, recirculating the flue gases, using low NO_X burners, and injecting water or steam.

Operating with low excess air involves restricting the amount of combustion air to the lowest possible level while maintaining efficient and environmentally compatible boiler operation. Because less oxygen is introduced into the combustion zone, NO_X formation is inhibited. Adjustments to the air supply may affect normal boiler operation and may reduce operational flexibility. The effectiveness of limiting excess air varies from boiler to boiler, but typical NO_X reductions are 10 to 25 percent from uncontrolled levels.

Overfire air (OFA) is a method where some of the total combustion air is diverted from the burners and injected through ports above the top burner level. This staged combustion reduces fuel-based NO_X formation in the oxygen-deficient primary combustion zone and limits thermal NO_X formation because of the lower peak flame temperature (combustion occurs over a larger portion of the furnace). For oil-fired boilers, OFA typically reduces NO_X emissions by 15 to 45 percent.

Flue gas recirculation (FGR) involves reinjecting a portion of the cooled flue gas into the combustion chamber. FGR dilutes the oxygen concentration in the combustion zone and depresses peak flame temperature by adding a large amount of cooled gas to the fuel-air mixture, resulting in less thermal NO_X formation. FGR reduces NO_X emissions by about 40 to 60 percent in oil-fired boilers.

Low NO_X burners (LNB) are designed to control fuel/air mixing and increase heat dissipation. These alternative burners can be installed on new boilers or retrofitted on older units. LNB technology integrates staged combustion in the burner. A typical LNB creates a fuel-rich primary combustion zone, thus lowering the formation of fuel-based NO_X. At the same time, limited combustion air reduces the flame temperature, minimizing the formation of thermal NO_X. Combustion is completed in a lower-temperature, fuel-lean zone. LNB retrofits have been shown to reduce NO_X formation by 30 to 55 percent.

Water or steam can be injected into the boiler combustion zone to reduce the peak flame temperature, with a corresponding reduction in thermal NO_X formation. Water/steam injection can reduce NO_X emission by up to 75 percent in gas-fired boilers and slightly less in oil-fired boilers.

Selective Non-Catalytic Reduction (SNCR)

SNCR is a post-combustion technology that involves injecting ammonia or urea into specific temperature zones in the upper furnace or convective pass. The ammonia or urea reacts with NO_X in the flue gas to produce nitrogen and water. The effectiveness of SNCR depends on the temperature where reagents are injected, the mixing of the reagent in the flue gas, the residence time of the reagent within the required temperature window, the ratio of reagent to NO_X, and the sulfur content of the fuel that may create sulfur compounds that deposit in downstream equipment. There is limited commercial experience with SNCR from which to judge its effectiveness for oil-fired boilers. NO_X reductions of 35 to 60 percent have been achieved through the use of SNCR on some oil-fired boilers operating in the United States.

Selective Catalytic Reduction (SCR)

SCR is another post-combustion technology that involves injecting ammonia into the flue gas in the presence of a catalyst to reduce NO_X to nitrogen and water. The SCR reactor can be located at various positions in the process, including upstream of an air heater and particulate control device, or downstream of an air heater, particulate control device, and flue gas desulfurization system. The performance of SCR is influenced by flue gas temperature, fuel sulfur content, ammonia-to-NO_X ratio, inlet NO_X concentration, space velocity, catalyst design, and catalyst condition. NO_X emission reductions of about 75 to 90 percent have been obtained with SCR on coal-fired boilers operating in the U.S.

2.1.1 Potential Costs of NO_X Controls

The estimated costs of NO_X emission controls for SNCR and SCR at Newington Station Unit NT1 are presented in Table 2-1. These estimates are based on assumptions used in EPA's Integrated Planning Model for the EPA Base Case 2006 (V.3.0), for retrofitting an EGU the size of Unit NT1. For SNCR, the total annual cost is estimated to be about \$730,000, or \$1,030/ton of NO_X removed. For an SCR system, the total annual cost is estimated to be \$1,410,000 or \$1,180/ton. Because Unit NT-1 is primarily a peak-load generator, these estimates are based on a 20-percent capacity factor.

Table 2-1. Estimated NO_X Control Costs (2008$)

Control Technology	Capital Cost ($/kW)	Capital Cost $	O&M Cost ($/yr)	Total Annual Cost ($/yr)	Average Cost ($/ton)
SNCR	8.2	3,300,000	450,000	730,000	1,030
SCR	28.8	11,500,000	440,000	1,410,000	1,180

Estimates are derived from USEPA, *Documentation for EPA Base Case 2006 (V.3.0) Using the Integrated Planning Model*, November 2006. Costs are scaled for boiler size. All costs are adjusted to 2008 dollars. Total annual cost is for retrofit of a 400-MW unit with 20% capacity factor and 701million kWh annual generation. Total annual cost includes amortization of capital cost over 15 years at 3.0% interest rate. Average cost per ton is based on an estimated 704 tons of NO_X removed for SNCR and an estimated 1,196 tons of NO_X removed for SCR.

Unit NT1 already employs combustion control technology (i.e., low NO_X burners, overfire air, and water/steam injection) to mitigate NO_X emissions. Low-NO_X burners typically operate in a cost range of $200 to $500 per ton of NO_X removed (NESCAUM, *Assessment of Control Technology Options for BART-Eligible Sources*, March 2005); however, this cost range would be more likely to apply to larger plants operating at higher capacity factors than Newington Station.

2.1.2 Other Environmental and Energy Impacts of NO_X Controls

SNCR and SCR both use urea or anhydrous ammonia. Ammonia is a regulated toxic air pollutant in New Hampshire. Facilities using these technologies must limit their ammonia emissions, which may be released either in their flue gases or as fugitive emissions from the handling and storage of urea or anhydrous ammonia. A facility must also maintain a risk management plan if the quantities of stored ammonia exceed the applicable regulatory threshold.

Ammonia from SNCR that becomes entrained in the fly ash may affect the resale value or disposal cost of the ash. Ammonia in the flue gas may produce a more visible plume, depending on the ammonia concentration in the gas stream. High ammonia concentrations in the boiler from SNCR can react with sulfate to form ammonium bisulfate, which deposits on the economizer, air heater, and other surfaces. Ammonium bisulfate can also plug filter bags in a baghouse. SNCR may generate nitrous oxide emissions, a greenhouse gas.

With SCR, the formation of ammonium bisulfate may be exacerbated by the ability of this catalyst-based technology to oxidize SO_2 to SO_3, resulting in higher sulfate concentrations than would otherwise exist. Ammonium bisulfate formation can be reduced by controlling excess ammonia and using catalysts that minimize SO_2 oxidation. The air heater and other surfaces where the ammonia bisulfate may deposit must be washed periodically. Washing helps to maintain the efficiency of the air heater and prevents plugging to allow the free flow of flue gases through it. An SCR may also require a fan upgrade to overcome additional pressure drop across the catalyst. The increase in fan capacity consumes a small amount of energy.

NO_X emission reductions provide environmental and public health benefits beyond visibility improvement – most notably, reductions in acid rain and ground-level ozone. NO_X is a chemical precursor to ozone formation and is one of the primary compounds contributing directly to acid rain formation. A decrease in acid rain production improves water quality and the health of ecosystems sensitive to low pH.

2.2 Available Retrofit Technologies for PM Control

PM control technologies available and potentially applicable to Unit NT1 are electrostatic precipitators, fabric filters, mechanical collectors, and particle scrubbers.

Electrostatic Precipitators (ESPs)

Electrostatic precipitators capture particles through the use of electrodes, which are electrical conductors used to make contact with a non-metallic part of a circuit. An ESP consists of a small-diameter negatively charged electrode (usually a set of individual wires or a grid) and a grounded positively charged plate. In operation, a strong electric charge from the negatively charged electrode sets up a one-directional electric field. When particle-laden gases pass through this electric field, the particles become charged and are then drawn to the positive collecting surface (the plate), where they are neutralized. The particles are then collected by washing or knocking the plate, causing the particles to fall into a collection hopper. Existing electrostatic precipitators are typically 40 to 60 percent efficient. New or rebuilt ESPs can achieve collection efficiencies of more than 99 percent.

Fabric Filters

Fabric filtration devices, or baghouses, incorporate multiple fabric filters/bags inside a containment structure. These devices work on the same principal as a vacuum cleaner bag. The particle removal efficiency of the fabric filter system depends on a variety of particle and operational parameters. The physical characteristics of particle size distribution, particle cohesion, and particle electrical resistivity are important variables. Operational parameters affecting collection efficiency include air-to-cloth ratio, operating pressure loss, cleaning sequence, interval between cleanings, and cleaning intensity. The structure of the fabric filter, filter composition, and bag properties also affect collection efficiency. Collection efficiencies of baghouses may exceed 99 percent.

Mechanical Collectors and Particle Scrubbers

Mechanical collectors, such as cyclones, are most effective at collecting coarse particulate matter (i.e., particles with a diameter of 10 micrometers or larger). Finer particles escape cyclones along with the flue gases. For this reason, mechanical collectors are generally most useful when used in conjunction with other pollution control equipment. The typical collection efficiency of mechanical collectors is about 85 percent for larger particle sizes.
Scrubbing systems involve the injection of water and/or chemicals into the flue gas to wash unwanted pollutants from the gas stream through physical or chemical absorption/adsorption. Scrubbing systems have been shown to reduce PM_{10} emissions by 50 to 60 percent but are generally less effective for removal of fine particles.

Because mechanical collectors and particle scrubbers are more costly and less efficient than other control options (i.e., ESPs, baghouses), these lower-performing technologies are rarely used today for removing particulate matter from power plant emissions. Consequently, mechanical collectors and scrubbers are not considered further in this analysis.

2.2.1 Potential Costs of PM Controls

Table 2-2 presents cost data for PM controls as developed from NESCAUM's *Assessment of Control Technology Options for BART-Eligible Sources*, March 2005. Approximate cost ranges are provided for two types of ESPs and two types of fabric filters applicable to a retrofit installation the size of Unit NT1. Capital and operating costs are based on flue gas flow rates in actual cubic feet per minute (acfm).

Table 2-2. PM Control Costs (2008 $)

Control Technology	Capital Cost ($/kW)	Capital Cost $	O&M Cost ($/yr)	Total Annual Cost ($/yr)	Average Cost ($/ton)
Dry ESP	73-194	29.3-78.1 million	1.4-2.4 million	3.8-9.0 million	$27,000-63,000
Wet ESP	73-194	29.3-78.1 million	0.8-2.0 million	3.2-8.5 million	$23,000-60,000
Fabric filter - reverse air	82-194	33.2-78.1 million	2.0-3.0 million	4.8-9.6 million	$14,000-29,000
Fabric filter - pulse jet	58-194	23.4-78.1 million	2.7-3.9 million	4.7-10.4 million	$14,000-31,000

Reference: NESCAUM, *Assessment of Control Technology Options for BART-Eligible Sources*, March 2005. (Note that these costs were developed for coal-fired boilers.) All costs are adjusted to 2008 dollars. Total annual cost is for retrofit of a 400-MW unit with 20% capacity factor and flue gas flow rate of 1.71 million acfm. Total annual cost includes amortization of capital cost over 15 years at 3.0% interest rate. Average cost per ton is based on 142 tons of PM removed for ESPs and 335 tons of PM removed for fabric filters.

The costs for ESPs and fabric filters are of similar magnitude, with total annual costs ranging from about \$3.2 million to \$10.4 million, or \$14,000 to \$63,000 per ton of PM removed. Because Unit NT1 already has an ESP installed and operating, the tabulated costs are useful for comparative purposes only.

2.2.2 Other Environmental and Energy Impacts of PM Controls

PM controls collect particulate matter, or fly ash, suspended in the flue gases. In some cases, the fly ash is injected back into the boiler, an arrangement that improves boiler efficiency by recapturing the residual heating value of the fly ash. If the fly ash is not reinjected, it must be either landfilled or reclaimed, e.g., as a supplement in concrete production or as a component in other manufactured products.

2.3 Retrofit Technologies for SO_2 Control

SO_2 control technologies available and potentially applicable to Unit NT1 are wet flue gas desulfurization and use of low-sulfur fuels.

Wet Flue Gas Desulfurization

The flue gas desulfurization (FGD) process – commonly known as "scrubber" – uses an alkaline reagent to absorb SO_2 in the flue gas. For coal-fired power plants, the reagent is usually lime or limestone; and the reaction product is calcium sulfite or calcium sulfate. The solid compounds are collected and removed in downstream process equipment. Calcium sulfate (gypsum) sludge produced in FGDs can be recycled into saleable byproducts such as wallboard, concrete, and fertilizer. Sulfate products that are not recycled must be landfilled. The FGD process may be either dry (injection of the chemical reagent in dry form) or wet (application of the reagent in liquid or slurry form). To date, wet scrubbers are more commonly used, with alkali slurries as the SO_2 absorbent medium. Lime/limestone scrubbers, sodium scrubbers, and dual alkali scrubbers are among the commercially proven wet FGD systems. SO_2 removal efficiencies for existing wet limestone scrubbers range from 31 to 97 percent with an average of 78 percent (NESCAUM, 2005). Scrubbers may also be effective for the removal of particulate matter, mercury, and other air pollutants. Wet regenerable (meaning the reagent material can be treated and reused) FGD processes are an attractive option because they allow higher sulfur removal rates and produce minimal wastewater discharges.

Low-Sulfur Fuels

Because SO_2 emissions are directly related to the sulfur content of the fuel burned, reducing the amount of sulfur in the fuel reduces SO_2 emissions. For facilities that burn fuel oil, switching to a lower-sulfur fuel oil may be a cost-effective control option. For facilities that have the option to replace fuel oil with natural gas or can co-fire with natural gas, increasing the use of natural gas is an effective control strategy because SO_2 emissions from burning natural gas are negligible in comparison to those from burning fuel oil. The resulting emission reductions are roughly proportional to the amount of natural gas burned on a Btu-equivalent basis.

2.3.1 Potential Costs of SO_2 Controls

There is little or no experience with, or cost data on, flue gas desulfurization at oil-fired power plants. However, the technology is similar to FGD for coal-fired plants. Therefore, the costs of an FGD system for PSNH Newington Station may be crudely approximated by extrapolating from the costs of FGD for PSNH Merrimack Station.

The flue gas desulfurization system at Merrimack Station is being installed to reduce mercury emissions (with SO_2 removal as a co-benefit) at its two coal-fired boilers. These units have a combined generating capacity of 433 MW, or slightly greater than the capacity of Newington Station Unit NT1. The company's recently revised capital cost estimate for the wet limestone FGD system is \$457 million, or \$1,055/kW (both amounts in 2008\$), which is said to be in line with project costs for multiple-unit scrubber installations occurring elsewhere in the United States. However, PSNH's estimated cost per kilowatt is at least triple the cost range for FGD systems as reported in MACTEC Federal Programs, Inc., "Assessment of Reasonable Progress for Regional Haze in MANE-VU Class I Areas," Final, July 9, 2007 (see Reasonable Progress Report, Attachment Y). The PSNH estimated cost is also more than double the recent estimate of \$300/kW to \$500/kW as reported in a 2008 survey of FGD systems (George W. Sharp, "What's That Scrubber Going to Cost?," *Power*, March 1, 2009). The higher cost-per-kW for Unit MK2 may reflect recent industry-wide increases in raw material, manufacturing, and construction costs.

Using the latest Merrimack Station estimate of $1,055/kW for scaling purposes, the total capital cost of a wet limestone FGD system for Newington Station Unit NT1 would be roughly $422,000,000. Much caution is necessary in relating this number to the Newington facility: Note that the cost of FGD on oil-fired boilers previously has been estimated to be about *twice* the cost of FGD on coal-fired boilers of comparable size (NESCAUM, 2005).

The costs of fuel switching at Unit NT1 would depend on the incremental costs of purchasing the lower-sulfur fuel at prevailing market prices. The long-term price differential between 1.0%-sulfur (low-S) residual fuel oil and 2.0%-sulfur residual fuel oil is estimated to be about 7.5 cents/gallon. The differential between 0.5%-sulfur (ultra-low-S) residual fuel oil and 2.0%-sulfur residual fuel oil is estimated to be about twice this amount, or 15 cents/gallon (both estimates in 2008$ based on Energy Information Agency compiled price data for the period 1983-2008.) Using these unit prices, the total cost of switching to low-S residual fuel oil is approximately $3.3 million per year, or $1,900 per ton of SO_2 emissions removed; and the cost of switching to ultra-low-S residual fuel oil is approximately $6.6 million per year, or also $1,900 per ton of SO_2 emissions removed (both estimates based on 2002 actual fuel oil usage; note that fuel oil usage in 2006-2008 has been below 2002 levels). These results imply that the cost of fuel switching may be relatively constant on a $/ton basis as long as supplies are adequate.

Table 2-3 summarizes the estimated costs of SO_2 control options for PSNH Newington Station Unit NT1. When switching to a lower-sulfur fuel, the actual cost would vary in proportion to the applicable fuel price differential. The estimated costs for switching from 2.0%-S residual fuel oil to 1.0%-S or 0.5%-S residual fuel oil are listed. Volatile energy commodity prices in recent years and the uncertainty of future fuel supplies make it difficult to provide a useful estimate of the cost of substituting natural gas for residual fuel oil, so no cost estimate for this option is given.

Table 2-3. SO_2 Control Costs (2008$)

Control Technology	Capital Cost ($/kW)	Capital Cost ($)	O&M Cost ($/yr)	Total Annual Cost ($/yr)	Average Cost ($/ton)
FGD	1,055	422,000,000	unknown	unknown	unknown
Switch to 1.0%-S oil	—	—	3,300,000	3,300,000	$1,900
Switch to 0.5%-S oil	—	—	6,600,000	6,600,000	$1,900
Capital cost estimate for FGD is based on reported cost per kilowatt-hour for FGD system at PSNH Merrimack Station. Actual costs for Newington Station could be much higher. O&M costs for fuel switching are based on 2002 annual fuel usage of 44,140,000 gallons and estimated fuel price differential of 7.5 or 15 ¢/gallon for substitution of 1.0%-S or 0.5%-S residual fuel oil, respectively.					

2.3.2 Other Environmental and Energy Impacts of SO_2 Controls

An FGD system typically operates with high pressure drops across the control equipment, requiring increased energy usage for blowers and circulation pumps. Some configurations of FGD systems also require flue gas reheating to prevent physical damage to the equipment, resulting in higher fuel usage. IPM documentation indicates that a wet FGD system reduces the capacity of the unit by about 2 percent.

Flue gas desulfurization has impacts on the operation of solid waste and wastewater management systems. In addition to removing SO_2, the FGD process removes mercury and other metals and solids. Often, gypsum produced in a limestone FGD process is recycled or sold to cement manufacturers; otherwise, the sludge must be stabilized and placed in an approved landfill. Gypsum must be dewatered before it can be handled, resulting in a wastewater stream that requires treatment. This wastewater increases the sulfates, metals, and solids loadings on the receiving wastewater treatment plant. Sometimes a clarifier is required to remove wastewater solids coming from the FGD system.

Wet FGDs increase the amount of water vapor entrained in the flue gas. The result is a more visible plume at the stack outlet.

Switching to lower-sulfur fuel oil generally reduces boiler maintenance requirements because less particulate matter is emitted. With fewer material deposits occurring on internal boiler surfaces, the intervals between cleanings/outages can be longer. Also, because lower-sulfur oil reduces the formation of sulfuric acid emissions, corrosion is reduced and equipment life is extended.

3. DISCUSSION OF CURRENT POLLUTION CONTROL EQUIPMENT AND EMISSIONS

3.1 Discussion of Current NO_X Emissions and Controls

PSNH Newington Station Unit NT1 currently operates with low-NO_X burners, an overfire air system, and water injection to minimize NO_X formation. To comply with NO_X RACT requirements, the air permit limits NO_X emissions from this unit to a daily average of 0.35 lb/MMBtu when burning oil and 0.25 lb/MMBtu when burning a combination of oil and gas. Actual NO_X emissions from this unit were 943 tons in 2002.

3.2 Discussion of Current PM Emissions and Controls

Unit NT1 has an electrostatic precipitator to capture PM emissions. The facility's air permit sets an emission limit of 0.22 lb/MMBtu total suspended particulate matter (filterable TSP) for this unit. Actual TSP emissions from this unit were 198 tons in 2002.

3.3 Discussion of Current SO_2 Emissions and Controls

Sulfur dioxide emissions are partially controlled at PSNH Newington Station by existing limits on fuel oil sulfur content. Permitted fuel sulfur limits are 2.0% sulfur by weight for No. 6 fuel oil and 0.4% sulfur by weight for No. 2 fuel oil. Unit NT1 is subject to an annual emissions cap of 55,150 tons of SO_2 for all electrical generating units at PSNH's Merrimack, Newington, and Schiller Stations combined. Actual SO_2 emissions from Unit NT1 were 5,226 tons in 2002.

4. REMAINING USEFUL LIFE OF UNIT

Where a reasonable control option is available for a BART-eligible unit, the unit should be controlled in a manner consistent with BART and the expected useful life of the unit. Originally, electric generating units were estimated to have a life expectancy of 30 to 40 years, but many units are lasting 50 years or more. In many cases, it is less expensive to keep existing units operating than to build replacement facilities and/or new transmission lines. Newington Station Unit NT1 was built in 1969. However, because this facility runs primarily on fuel oil, its remaining useful life may depend more on future commodity supplies/prices and other external factors than on the longevity of plant equipment.

5. DEGREE OF VISIBILITY IMPROVEMENT ANTICIPATED FROM BART

The New Hampshire Department of Environmental Services (NHDES) conducted a screening-level analysis of the anticipated visibility effects of BART controls at PSNH Newington Station Unit NT1. Specifically, one modeling run using the CALGRID photochemical air quality model was performed to assess the effects of switching to lower-sulfur fuel for this unit. The simulation covered the full summer modeling episode (from May 15 to September 15, 2002) with MANE-VU's 2018 beyond-on-the-way (BOTW) emissions inventory scenario as a baseline. The BOTW emissions scenario reflects controls from potential new regulations that may be necessary to attain National Ambient Air Quality Standards and other regional air quality goals, beyond those regulations that are already "on the books" or "on the way."

The CALGRID model outputs took the form of ambient concentration reductions for SO_2, $PM_{2.5}$, and other haze-related pollutant within the region. NHDES post-processed the modeled concentration reductions to estimate the corresponding visibility improvements at Class I areas such as Acadia National Park, Moosehorn National Wildlife Refuge, and Lye Brook Wilderness Area (i.e., concentration impacts were converted to visibility impacts). Visibility can be quantified using deciviews, a logarithmic unit of measure to describe increments of visibility change that are just perceptible to the human eye.

Based on the modeling results, switching to lower-sulfur fuel oil for Unit NT1 is expected to reduce maximum predicted 24-hour average SO_2 concentration impacts by 2 $\mu g/m^3$ and maximum predicted 24-hour average $PM_{2.5}$ concentration impacts by 0.1 $\mu g/m^3$. Reductions in the maximum predicted concentrations of SO_2, $PM_{2.5}$, and other haze-related pollutants, combined, would yield negligible visibility improvement at the affected Class I areas.

6. DETERMINATION OF BART

Based on the completed review and evaluation of existing and potential control measures for PSNH Newington Station Unit NT1, it is determined that the NO_X, PM, and SO_2 controls described below represent Best Available Retrofit Technology for this unit.

6.1 Selecting a Pollution Control Plan for NO_X

Use of low excess air reduces NO_X emissions but can often result in greater PM and/or CO emissions. Many of the NO_X reduction benefits acquired through the implementation of low excess air are already being achieved at Unit NT1 through the use of low-NO_X burners and overfire air, so the application of low excess air would be redundant in this case. Flue gas recirculation reduces the peak flame temperature in much the same way as overfire air and has the additional benefit of reducing the oxygen content in the combustion zone, leading to further reductions in NO_X formation. Because Unit NT1 operates with an existing overfire air system, and because this boiler has already been modified by the installation of natural gas lancers, FGR is economically impractical and might also be physically infeasible.

The NO_X emission reductions being achieved at Unit NT1 through various combustion control technologies are a substantial improvement over no controls. The additional reductions in NO_X emissions that would result from adding SCR or SNCR would come at a cost of about \$0.7 to \$1.3 million annually, with incremental NO_X reductions in the 300 to 700 ton/year range. This cost range does not include costs related to redesign of the site layout to accommodate existing spacial constraints. Also, this estimate is based on 2002 emission levels, when the plant's capacity factor was around 20 percent. With the capacity factor having fallen to less than 10 percent over the period 2006-2008, it is difficult today to justify additional technology retrofits to reduce NO_X emissions at this facility.

Another consideration with SCR or SNCR is flue gas and fugitive ammonia emissions. Based on past operation of Unit NT1 and on typical ammonia "slip" rates, it is estimated that fugitive ammonia emissions with either technology would be in the vicinity of 32 tons annually. Ammonia is a regulated toxic air toxic pollutant in New Hampshire and is also a significant contributor to visibility impairment.

For these reasons, SCR and SNCR are not cost-effective as Best Available Retrofit Technology for this facility and will not be considered further. The existing controls, which include low- NO_X burners, overfire air, and water injection, are determined to be BART for Newington Station Unit NT1.

6.2 Selecting a Pollution Control Plan for PM

PSNH currently operates an electrostatic precipitator on Unit NT1. ESPs perform with removal efficiency rates similar to those of fabric filters but operate at about half the cost for plants of this size. Because of the estimated cost differential and the fact that an ESP is already installed and operating, the existing ESP is determined to satisfy BART requirements for PM removal at PSNH Newington Station Unit NT1.

6.3 Selecting a Pollution Control Plan for SO_2

Flue gas desulfurization is a potential SO_2 control option for PSNH Newington Station Unit NT1. However, the cost per ton for FGD on oil-fired boilers is estimated to be about twice the cost of this technology on coal-fired boilers and could be well in excess of $1,000/kW for Newington Station. Given the high costs of this option, it is apparent that FGD would be uneconomical as a retrofit for a peak-demand plant the size of Unit NT1.

Use of a lower-sulfur fuel is a practical option for controlling SO_2 emissions at Newington Station. When natural gas is available at reasonable cost relative to residual fuel oil, natural gas is the preferred fuel because of its very low sulfur content. Otherwise, use of low-sulfur residual fuel oil is a reasonable option. For relatively minor increases in the cost of fuel, switching to 1.0%-S or 0.5%-S residual fuel oil provides significant reductions in fuel sulfur content with proportional reductions in SO_2 emissions.

When not firing on natural gas, Unit NT1 has burned 2.0%-sulfur residual fuel oil (actual average fuel sulfur content was 1.2% in 2002). It is estimated that switching to 1.0%-sulfur residual fuel oil would reduce SO_2 emissions by about one-third, and switching to 0.5%-sulfur residual fuel oil would cut SO_2 emissions by about two-thirds. At the 2002 production level of 700 million kilowatt-hours, estimated annual costs (long-term average, 2008$), would be about $3.3 or $6.6 million (equivalent to $0.0047 or $0.0094 per kWh), respectively. The cost per kilowatt-hour would vary more or less in proportion to the fuel price differential and would not change significantly with increases or decreases in production level.

Fuel switching could be accomplished without capital outlay and would have predictable costs tied directly to fuel consumption and fuel price differentials. A major consideration is fuel availability. In recent years, there have been sudden and dramatic swings in the price of natural gas relative to fuel oil as supply/demand has shifted. The future price and availability of natural gas are difficult to discern. While regional and national supplies of 1.0%-sulfur residual fuel oil appear to be adequate to meet current demand, the present and future availability of 0.5%-sulfur residual fuel oil, in particular, is uncertain and speculative.

After consideration of projected costs, ease of implementation, and fuel availability, it is determined that using 1.0%-sulfur (low-sulfur) residual fuel oil is currently the Best Available Retrofit Technology for PSNH Newington Station Unit NT1 when natural gas is not available at reasonable cost. The use of 0.5%-sulfur (ultra-low-sulfur) residual fuel oil remains a future possibility that should be re-evaluated within the next few years. A further reduction in the sulfur content of fuel oil burned at this facility would be consistent with MANE-VU's plan to reduce sulfur levels to 0.25-0.5% for all fuel oils throughout the region by 2018.

7. SUMMARY AND CONCLUSIONS

Table 7-1 summarizes Best Available Retrofit Technology for PSNH Newington Station Unit NT1 for the pollutants NO_X, PM, and SO_2. This summary includes existing controls considered as meeting or exceeding BART requirements as well as proposed measures consistent with the BART rule. Mandating the use of low-sulfur residual fuel oil will require a modification to the facility's air permit. Given the prevailing uncertainty over the future price and availability of natural gas, the use of natural gas is not being specified as a BART requirement.

Table 7-1. Summary of BART Determinations for Unit NT1

Pollutant	Current Emission Controls	BART
NO_X	Low NO_X burners, overfire air, and water injection	Low NO_X burners, overfire air, and water injection
PM	ESP	ESP
SO_2	2.0% sulfur content limit on residual fuel oil; 0.4% sulfur content limit on distillate fuel oil	1.0% sulfur content limit on residual fuel oil; 0.4% sulfur content limit on distillate fuel oil

NEW HAMPSHIRE BART ANALYSIS: Newington Station Unit NT1 (400 MW)

DRAFT 05-06-09

Pollutant	Emission Control Technology	Control Level	Uncontrolled Emissions ton/yr	Controlled Emissions ton/yr	Emission Reductions ton/yr	Estimated Cost of Emission Controls[6]						
							Capital $	Capital $/kW	O&M $/yr	Total Annual $/yr	Average $/ton	Ref./ Note
NO_X	LNB + combustion modifications (existing)	33%	1,407 [1]	943 [2]	464		—	—	—	—	—	
	SCR	85%	1,407 [1]	211	1,196		11,510,100	37	441,685	1,405,886	1,175	8
	SNCR	50%	1,407 [1]	704	704		3,298,475	12	451,026	727,339	1,034	8
PM	ESP (existing)	42%	338 [2]	196 [2]	142		—	—	—	—	—	
	Fabric Filters	99%	338 [2]	3	335	min.	23,426,952	59	2,733,144	4,695,620	14,033	9
						max.	78,089,840	195	3,904,492	10,446,078	31,218	
SO_2	2.0%-S oil (existing)	0% [3]	5,226 [2]	—	—		—	—	—	—	—	
	Switch to 1.0%-S oil	33% [4]	5,226 [2]	3,484	1,742		—	—	—	3,310,808	1,901	10
	Switch to 0.5%-S oil	67% [5]	5,226 [2]	1,742	3,484		—	—	—	6,621,615	1,901	11
	FGD	90%	5,226 [2]	523	4,703		422,000,000	1,055	unknown	unknown	unknown	12

[1] Estimated.

[2] 2002 (baseline) emissions as taken from NHDES data summary derived from facility's annual emissions statement.

[3] Actual average fuel sulfur content was ~1.2% in 2002. Over period of 2002-07, average annual values ranged from 0.93 to 1.54% S with no discernable trend.

[4] Based on an assumed average fuel sulfur content of 0.8%.

[5] Based on an assumed average fuel sulfur content of 0.4%.

[6] All cost estimates adjusted to 2008 $.

[8] USEPA, *Documentation for EPA Base Case 2006 (V.3.0) Using the Integrated Planning Model*, November 2006.

[9] NESCAUM, *Assessment of Control Technology Options for BART-Eligible Sources*, March 2005.

[10] Stated costs represent premium for purchasing 1.0%-S oil at estimated price differential of 7.5¢/gal.

[11] Stated costs represent premium for purchasing 0.5%-S oil at estimated price differential of 15¢/gal.

[12] Based on $/kW estimated capital cost for comparable controls at Merrimack Station.

Newington Station Unit NT1: NO_X Controls

Plant type	oil- or natural-gas-fired boiler	
Capacity	400	MW
Maximum heat Input	4,350	MMBtu/hr
Capacity factor	20	%
Annual hours	8,760	hr/yr
Annual production	700,800,000	kWh/yr

Historical operation:

Year	2002	2003	2004	2005	2006	2007	2008
Operating hours	3,085	6,606	6,300	4,187	1,282	1,374	548
Total Heat Input*	7,223,832	26,414,481	22,477,521	16,060,698	3,600,581	4,303,867	1,231,841
Capacity factor**	19.0%	69.3%	59.0%	42.1%	9.4%	11.3%	3.2%

*MMBtu (from CEM data) **Based on ratio of total heat input to theoretical maximum heat input

Costs: 2004 $

Control Technology	Capital $/kW	Scaled Capital $/kW	Total Capital $	Total Annualized Capital $/yr	Fixed O&M $/kW/yr	Scaled Fixed O&M $/kW/yr	Scaled Fixed O&M $/yr	Variable O&M mills/kWh	Variable O&M $/yr	Total Fixed & Variable O&M $/yr	Total Annualized Cost $/yr	Emission Reductions tons/yr	Average Cost $/ton
SCR	32.20	25.26	10,105,443	846,533	0.99	0.78	310,695	0.11	77,088	387,783	1,234,316	1,196	1,032
SNCR	10.80	7.24	2,895,939	242,593	0.17	0.11	45,584	0.50	350,400	395,984	638,577	704	907

Costs: 2008 $ 2004 $ → 2008 $ 1.139 multiplier

Control Technology	Capital $/kW	Scaled Capital $/kW	Total Capital $	Total Annualized Capital $/yr	Fixed O&M $/kW/yr	Scaled Fixed O&M $/kW/yr	Scaled Fixed O&M $/yr	Variable O&M mills/kWh	Variable O&M $/yr	Total Fixed & Variable O&M $/yr	Total Annualized Cost $/yr	Emission Reductions tons/yr	Average Cost $/ton
SCR	36.68	28.78	11,510,100	964,201	1.13	0.88	353,882	0.13	87,803	441,685	1,405,886	1,196	1,175
SNCR	12.30	8.25	3,298,475	276,313	0.19	0.13	51,920	0.57	399,106	451,026	727,339	704	1,034

Cost Reference:

USEPA, *Documentation for EPA Base Case 2006 (V.3.0) Using the Integrated Planning Model*, November 2006.

Annualized cost basis:

Period, yrs	15
Interest, %	3.0
CRF	0.08377

Newington Station Unit NT1: PM Controls

Plant type	oil- or natural-gas-fired boiler	
Capacity	400	MW
Maximum heat Input	4,350	MMBtu/hr
Capacity factor	20	%
Annual hours	8,760	hr/yr
Annual production	700,800,000	kWh/yr
Flue gas flow rate	1,714,000	acfm

Historical operation:

Year	2002	2003	2004	2005	2006	2007	2008
Operating hours	3,085	6,606	6,300	4,187	1,282	1,374	548
Total Heat Input*	7,223,832	26,414,481	22,477,521	16,060,698	3,600,581	4,303,867	1,231,841
Capacity factor**	19.0%	69.3%	59.0%	42.1%	9.4%	11.3%	3.2%

*MMBtu (from CEM data) **Based on ratio of total heat input to theoretical maximum heat input

2004 $

Control Technology		Capital $/acfm	Total Capital $	Total Annualized Capital $/yr	Fixed O&M $/yr-acfm	Variable O&M $/yr-acfm	Total Fixed & Variable O&M $/yr	Total Annualized Cost $/yr	Emission Reductions tons/yr	Average Cost $/ton
Dry ESP	min.	15.00	25,710,000	2,153,727	0.25	0.45	1,199,800	3,353,527	142	23,616
	max.	40.00	68,560,000	5,743,271	0.65	0.60	2,142,500	7,885,771	142	55,534
Wet ESP	min.	15.00	25,710,000	2,153,727	0.15	0.25	685,600	2,839,327	142	19,995
	max.	40.00	68,560,000	5,743,271	0.50	0.50	1,714,000	7,457,271	142	52,516
Fabric Filter - Reverse Air	min.	17.00	29,138,000	2,440,890	0.35	0.70	1,799,700	4,240,590	335	12,673
	max.	40.00	68,560,000	5,743,271	0.75	0.80	2,656,700	8,399,971	335	25,103
Fabric Filter - Pulse Jet	min.	12.00	20,568,000	1,722,981	0.50	0.90	2,399,600	4,122,581	335	12,320
	max.	40.00	68,560,000	5,743,271	0.90	1.10	3,428,000	9,171,271	335	27,408

Cost Reference:

NESCAUM, *Assessment of Control Technology Options for BART-Eligible Sources*, March 2005.

Annualized cost basis:

Period, yrs	15
Interest, %	3.0
CRF	0.08377

Costs: 2008 $ 2004 $ → 2008 $ 1.139 multiplier

Control Technology		Capital $/acfm	Total Capital $	Total Annualized Capital $/yr	Fixed O&M $/yr-acfm	Variable O&M $/yr-acfm	Total Fixed & Variable O&M $/yr	Total Annualized Cost $/yr	Emission Reductions tons/yr	Average Cost $/ton
Dry ESP	min.	17.09	29,283,690	2,453,095	0.28	0.51	1,366,572	3,819,667	142	26,899
	max.	45.56	78,089,840	6,541,586	0.74	0.68	2,440,308	8,981,893	142	63,253
Wet ESP	min.	17.09	29,283,690	2,453,095	0.17	0.28	780,898	3,233,993	142	22,775
	max.	45.56	78,089,840	6,541,586	0.57	0.57	1,952,246	8,493,832	142	59,816
Fabric Filter - Reverse Air	min.	19.36	33,188,182	2,780,174	0.40	0.80	2,049,858	4,830,032	335	14,434
	max.	45.56	78,089,840	6,541,586	0.85	0.91	3,025,981	9,567,567	335	28,592
Fabric Filter - Pulse Jet	min.	13.67	23,426,952	1,962,476	0.57	1.03	2,733,144	4,695,620	335	14,033
	max.	45.56	78,089,840	6,541,586	1.03	1.25	3,904,492	10,446,078	335	31,218

Newington Station Unit NT1: SO_2 Controls

SO_2 Control Cost Calculations for Switching from #6 Fuel Oil @ 2.0% S to Lower-Sulfur Fuel Oils @ 1.0 or 0.5% S:

Fuel Type	Maximum (Nominal) Fuel Sulfur[1] %S by wt	Actual Fuel Sulfur %S by wt		Annual Fuel Usage[4] gal/yr	Annual SO_2 Emissions ton/yr		Switch to Lower-S Fuel %S by wt	Annual SO_2 Emission Reductions[7] ton/yr	Blended Fuel Price Differential[8] ¢/gal		$/yr	SO_2 Control Cost $/ton removed
#6 Residual Oil	2.0	1.2	2	44,144,100	5,226	5	—	—	—		—	—
#6 ULS Residual Oil	1.0	0.8	3	44,144,100	3,484	6	2.0 to 1.0%	1,742	7.5	9	$3,310,808	$1,901
#6 ULS Residual Oil	0.5	0.4	3	44,144,100	1,742	6	2.0 to 0.5%	3,484	15.0	10	$6,621,615	$1,901

1 Maximum allowable sulfur content of specified fuel.

2 Actual average sulfur content of fuel burned in 2002. In the period 2002-07, average annual values ranged from 0.93 to 1.54% S with no discernable trend.

3 Assumed average sulfur content of specified fuel as assayed.

4 Actual fuel usage in 2002.

5 Actual 2002 emissions from CEM data.

6 Estimated emissions based on stated fuel usage and estimated average sulfur content of specified fuel.

7 Estimated emission reductions after switch to specified lower-sulfur fuel.

8 Estimated price difference between residual oil @ >1.0%S and residual oil @ ≤1%S, based on EIA fuel price data for all U.S. locations, 1983-2008.

9 Estimated price difference between fuel @ 1.2%S (2002 actual) and fuel @ 0.8%S actual (1.0% nominal).

10 Estimated price difference between fuel @ 1.2%S (2002 actual) and fuel @ 0.4%S actual (0.5% nominal).

SO_2 Control Cost Calculations for Flue Gas Desulfurization:

As an approximation, assume that FGD capital cost for Newington Station would be comparable to that for Merrimack Station on a $/kW basis.

Merrimack Station has an estimated capital cost of $1,055/kW, based on PSNH's 2008 estimate of $457 million for Unit MK1 (113 MW) and Unit MK2 (320 MW) combined.

Newington Station Unit NT1 has a generating capacity of 400 MW (=400,000 kW).

Estimated capital cost for FGD on Unit NT1 = 400,000 kW × $1,055/kW = $422,000,000.